UTAH DIVISION OF AIR QUALITY
MODIFIED SOURCE PLAN REVIEW

S. Gale Chapman, President
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624

Project fee code: N0327-007

RE:	Intermountain Generating Station DAQE-749-01 Modification to Increase Power Generating Capacity Millard County, Utah CDS-A, ATT, Title V, Title IV, NSPS
REVIEW ENGINEER:	Milka M. Radulovic
DATE:	July 17, 2001
NOTICE OF INTENT SUBMITTED:	April 5, 2001
PLANT CONTACT:	Rand Crafts
PHONE NUMBERS:	(435) 864-6494
FAX NUMBER:	(435) 864-0994
SOURCE LOCATION:	850 West Brush Wellman Road Delta, Millard County, Utah
UTM COORDINATES:	4,374.4 km Northing, 364.2 km Easting, Zone 12 datum NAD27

APPROVALS:

Peer Engineer ______________________________

John Jenks

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the <u>PLAN REVIEW ENGINEER</u> should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A 30-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact______________________________

(Signature & Date)

OPTIONAL: In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. THIS IS STRICTLY OPTIONAL! If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307--415-5a through 5e or R307-415-7a through 7i.

> **"Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application)."**

Responsible Official______________________________

(Signature & Date)

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TYPE OF IMPACT AREA

Attainment Area .... Yes

NSPS .... Yes
40 CFR Part 60, Subpart Da (Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After September 18, 1978), and Subpart Y (Coal Preparation Plants)

NESHAP .... No
MACT .... No

Hazardous Air Pollutants (HAPs) .... Yes
Hazardous Air Pollutants Major Source .... Yes
(No HAPs involved in modification)

New Major Source .... No
Major Modification .... No
PSD Permit .... Yes
PSD Increment (modeling) .... No

Operating Permit Program
Minor .... No
Major .... Yes

Send to EPA .... Yes
Comment period 30-day

FOR MODIFIED SOURCES

The Notice of Intent is for a modification to an existing source. The following standards are applicable to this review:

NSPS applies to modification? .... No
PSD review of entire source required? .... No
NESHAPS applies to modification? .... No
HAPs involved in modification? .... No
TITLE V required for entire source? .... Yes
HAPs MAJOR for modification? .... No
NONATT MAJOR for entire source? .... No

Abstract

Intermountain Power Service Corporation (IPSC) operates the Intermountain Generating Station (IGS) coal fired steam-electric plant, consisting of two 875 MW units, located near Delta in Millard County. IPSC is requesting a modification to their current approval order (AO) DAQE-749-01 to uprate (increase) each unit's generating capacity from 875 to 950 MW. The following are the modifications needed at the plant for the proposed-uprate which will affect emissions:

1. Increase heat input through the main boilers
2. Add patented scrubber wall rings to provide more efficient SO_2 removal
3. Add more rows of tubes in the boiler super heating section

There will be other changes which will not directly affect emissions, such as:

1. Replacement of two existing high pressure turbines with two current technology and high efficiency turbines
2. Replace one existing relief valve with safety valve on each boiler, add one new helper cooling tower (for each unit) without increasing current total circulating flow rates and cycles of concentration, boiler feed pump performance upgrade, generator and isophase cooling enhancement, and others similar changes
3. Substituting emission rate limit of 0.024 grains per dry standard cubic feet for the Group I dust collectors with an alternate limit: monthly monitoring of a differential pressure across the dust collectors.
4. In addition to the requested changes, existing emissions from the existing cooling towers were added to the plant potential to emit.

Millard County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants. New Source Performance Standards (NSPS), Subpart Da and Subpart Y applies to this source. Boiler 1 & 2 are also Group 1, Phase II units under the Acid Rain Program. IPSC is a major source of NO_x, SO_2, CO, and PM_{10}. Title V of the 1990 Clean Air Act applies to this source. The Title V permit will be administratively amended after this AO has been issued.
The emissions, in tons per year, will change as follows: PM_{10} (+9.75), CO (+ 77.56), VOC (+ 0.69), HAPs (VOC and Non-VOC) (+1.221).

This modification did not trigger Prevention of Significant Deterioration (PSD) regulation review since the emission increases (based on base line actual emissions and projected future emissions) were below significant levels. However, IPSC will monitor and maintain post change emissions information and submit them to the Utah Division of Air Quality on an annual basis for a period of 5 years to demonstrate that this modification did not result in a significant emissions increase. If the submitted information indicates that emissions have increased as a consequence of the proposed change, at that time IPSC will be required to obtain a PSD permit.

The Notice of Intent (NOI) for the above-referenced project has been evaluated and has been found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an AO by the Executive Secretary of the Utah Air Quality Board.

A public comment period will be held in accordance with UAC R307-401-4. A NOI to approve will be published in the?????????????? on ????????, 2001. During the public comment period the proposal and the evaluation of its impact on air quality will be available for both you and the public to review and

comment. If anyone so requests a public hearing it will be held in accordance with UAC R307-401-4. The hearing will be held as close as practicable to the location of the source. Any comments received during the public comment period and the hearing will be evaluated.

Newspaper Notice

Intermountain Power Service Corporation (IPSC) operates the Intermountain Generating Station (IGS) coal fired steam-electric plant, consisting of two 875 MW units, located near Delta in Millard County. IPSC is requesting a modification to their current approval order (AO) DAQE-749-01 to uprate (increase) each unit generating capacity from 875 to 950 MW. The following is the requested modification:

1. Replacement of two existing high pressure turbines with two current technology and high efficiency turbines and addition of two helper cooling towers.

3. Substituting emission rate limit for the Group I dust collectors with an alternate limit.

4. Existing cooling tower emissions were added to the plant's potential to emit

Millard County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants. New Source Performance Standards (NSPS), Subpart Da and Subpart Y applies to this source. Boiler 1 & 2 are also Group 1, Phase II units under the Acid Rain Program. IPSC is a major source of NO_x, SO_2, CO, and PM_{10}. Title V of the 1990 Clean Air Act applies to this source.

This modification did not trigger Prevention of Significant Deterioration (PSD) regulation; however, IPSC will monitor, maintain and submit to the Utah Division of Air Quality on an annual basis for a period of 5 years post change emissions information to demonstrate that this modification did not result in a significant emissions increase. If the submitted information indicate that emissions have increased as a consequence of the proposed change, at that time IPSC will be required to obtain a PSD permit.

The Title V permit will be administratively amended after this AO has been issued.
It has been determined that the conditions of the Utah Administrative Code R307-401-6 and the Federal rules have been met. The Executive Secretary intends to issue an Approval Order after a 30-day public comment period is held. This public comment period is being held to receive and evaluate public input on the project proposed by IPSC.

I0 DESCRIPTION OF PROPOSAL

IPSC is requesting a modification to their current approval order (AO) DAQE-749-01 to uprate (increase) each unit generating capacity from 875 to 950 MW.

1 PROCESS DESCRIPTION AT THE EXISTING PLANT:

production of steam to IGS is a fossil-fuel fired steam-electric generating station that primarily uses coal as a fuel for the (SIC Code 4911). Both bituminous and subbituminous coals are used. Diesel fuel is are also combusted during the startup, shutdown, maintenance, performance, upsets and flame stabilization and used oil for energy recovery.

Approximately IGS is a two unit facility operating at a rated capacity of 875 megawatts (MW) each (gross) 3 million to 600,000 gallons of fuel oil including used oil are used each year in the production of electricity. Normal boiler operating capacity is about 6.2 million pounds per hour

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of steam flow at 2822 psi. The current boiler maximum capacity rating (MCR) is 6.6 million lbs steam per hour at 2975 psi.

IGS has in place bulk handling equipment for the unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes of this equipment are proposed. No changes in the usage of other raw materials or bulk chemicals are planned.

2 PROPOSED CHANGES:

IPSC will enhance steam flow characteristics through the high pressure (HP) section of each turbine used to generate electricity. This involves the replacement of the HP turbines with a modified design that improves performance and reliability. This modification in and of itself will not increase plant capacity, but will instead lower emissions due to decreased fuel use from the resulting increased performance.

Combined proposed modifications to other areas of the plant will increase plant generating capacity from 875 to 950 MW. These modifications consist of re-configuring critical points that presently prevent the full utilization of present equipment. Other changes are needed for reliability, performance and/or routine maintenance purposes.

Approximately 7.3 million tons of coal and 600,000 gallons of oil (including fuel oil) used each year in the production of electricity.

3 EMISSION CHARACTERISTICS:

The composition and physical characteristics of the emissions are expected to change as a result of the proposed modifications, indicated in the emission summary. The mass flow of chimney effluent may change proportionately with the change in the heat input.

The existing pollution control devices include low-NO_x burners, fabric filters, wet scrubbers and auxiliary equipment dust collectors.

4 POLLUTION CONTROL DEVICE DESCRIPTION:

The existing pollution control device equipment includes dual register low NO_x burners (B&W Mark V), GEESI baghouse type fabric filters for particulate removal, and GEESI flue gas desulfurization scrubbers. The existing low NO_x burners provide a nominal 60% reduction in potential combustion NO_x formation, the baghouse filters operate at nominal 99.95% efficiency, and the existing wet scrubbers operate at nominal 90% efficiency. Control equipment for the handling and transfer of solid material include dust collection filters.

This proposed project includes modifications to the flue gas flow through scrubber modules to increase SO_2 and acid gas removal at proposed higher emission flows.

5 EMISSION POINTS:

The present emission point for the IGS boilers is a lined chimney that discharges at 712 feet above ground level (5386 feet above sea level). The chimney location is 39° 39' 39" longitude, 112° 34' 46" latitude (UTM 4374448 meters Northing, 364239 meters Easting.).

Other emission points such as coal handling and the cooling towers are located on the same site proximate to the chimney.

6 SAMPLING/MONITORING:

Emissions from boiler combustion are continuously sampled and monitored at the chimney for nitrogen oxides, sulfur oxides, carbon dioxide, and volumetric flow. Opacity is measured at the fabric filter outlet. Other parameters recorded include heat input and production level (megawatt load). Monitoring will remain unchanged. Other emissions not directly monitored are calculated using engineering judgement, emission factors, and fuel analyses. The type and location of the monitors will not be changed.

7 OPERATING SCHEDULE:

IGS operates 24 hours per day, seven days per week. This will not change as a result of the proposed modifications.

8 CONSTRUCTION SCHEDULE:

Construction of the modifications will be performed in a staged manner to accommodate use of normal plant maintenance outage periods.

9 MODIFICATION SPECIFICATIONS:

The changes covered by the modification include:

- **High Pressure Turbine Retrofit:**

  The high pressure turbine on each unit at IGS is scheduled to be replaced with a current technology, high efficiency turbine. This unit will increase high pressure turbine efficiency from approximately 84% to over 92%. Additionally, the turbine will be sized to provide up to 8.6% additional output.

- **Cooling Tower Performance Upgrade:**

  The cooling towers on each unit at IGS are scheduled for performance enhancement modifications to increase heat rejection capacity. The enhancement consists of increasing cooling fill surface area by approximately 20% by constructing a new helper cooling tower for each unit. Total current circulation flow rates and cycles of concentration will not change. However, flow will be reduced to the present towers by 20%, and redirected to the new helper towers to allow for a larger differential temperature change. To accommodate this expansion, cooling tower transformers feeding the cooling tower fan motors and new towers will be upgraded as well.

- **Boiler Safety Valve Additions:**

Rather than add new safety valves, IPSC will replace one existing electro relief valve (ERV) with one main steam safety valve on each unit. This will address reliability concerns with the existing valves and accommodate the planned increase in generation capacity.

- **Generator Cooling Enhancement:**

IPSC intends to upgrade the current generator and stator cooling systems.

- **Isophase Bus Cooling Enhancement**:

The 26kv generator electrical bus feeding the main step-up transformer will be upgraded to enhance the current isophase bus duct cooling systems.

- **Large Motor Bus Loading Equalization:**

IPSC plans to equalize the loading between the large and small motor bus. Due to limited tap adjustment capability on the auxiliary transformers feeding these load centers, several motors will be moved from one supply to the other in order to maintain required motor terminal voltages as unit output is increased.

- **Boiler Feed Pump Performance Upgrade:**

The boiler feed pump will be enhanced with improved bearing housings, flow path smoothing, and impeller clearance modifications to provide increased pump output and reliability.

- **Main Step-up Transformer Cooling:**

The step-up transformers will be modified to increase the transformer cooling system capacity for better temperature control of the transformer oil, core, and housing.

- **High Pressure Heater Drain Line Modifications:**

High pressure heater drain lines will be modified to eliminate resonant vibration at increased load.

- **Boiler Modification**:

A comprehensive study was performed by the manufacturer of the boilers (Babcock & Wilcox). This study reviewed all aspects of boiler operation at the new turbine output levels. The study also included evaluation of current technologies and operating practices for minimizing emissions, without the need to replace burners. The study recommended addition of surface area specific to primary superheat section. IPSC proposes to add 24 rows of superheat tubes across the full back-pass (convective section) of each boiler. This modification will help eliminate transient temperature anomalies and provide stable and efficient operation at the new higher rating.
Since the facility already has low-NO_x burners, to stay below significant net increases in NO_x minor adjustments will be done (such as how coal is combusted, i.e., biased firing,

burners-in-service re-arrangement, adjustments of the burner excess air, adjustments of the frequency of soot-blowing, etc) to the boiler combustion process.

- **Circulating Water Makeup Modifications:**

A new circulating water makeup design will support increased makeup requirements and add a degree of redundancy to the system.

Modification Affecting Emissions

- **Increase Fuel Flow (Heat Input):**

In order to utilize the increased capacity, coal combustion will increase approximately 5.9%.

- **Scrubber Wall Ring:**

Patented wall rings will be installed in all twelve (12) scrubber absorber vessels to move flow back to the center of the vessel, preventing slip, and providing more efficient SO_2 and acid gas capture in the flue gas.

- **PRODUCTION SUMMARY:**

The proposed project will increase generation capacity from 875 to approximately 950 MWhe, with steam flow design increasing from 6.6 to 6.9 million pounds per hour. Design heat input will increase from 8,500 to 9,225 million Btu per hour, requiring an increase from 5.3 to 5.6 million tons of coal (based on the current coal quality) each year. There will be no NO_x emission increase due to a better, stable, more efficient combustion process and adding of superheat tubes elimination of transient temperature anomalies and provide stable and efficient operation at the new higher rating. Therefore, hourly emission limit for NO_x is decreased in proportion with fuel input increase.

- **Group I Dust Collectors Limit**

  IPSC *is requesting that current emission limit of* 0.024 *grains per dry standard cubic feet* be replaced with an alternate limit: monitoring of differential pressure drop across the Group I duct collector fabric filters. This limit will be monitored on a monthly basis.

- Existing Cooling Tower emissions were added to the plant's potential to emit since they were not shown in the previous reviews.

Applicability of Prevention of Significant Deterioration (PSD) rules to new and modified sources

The determination to require a PSD permit depends on whether a new source or modification to a source is "major." In the Utah Administrative Rules, which mirrors Utah and federal statute, a "major modification" is defined at R307-101-2, Definitions, to mean "any physical change in or change in the method of operation of a major source that would result in a significant net emissions increase....."

The project described herein constitutes a physical and operational change to the Intermountain Power facility. However, the proposed change will not result in a significant net emissions increase.

To show that an emissions increase is not significant, an electric steam generating facility such as Intermountain must show that its future representative actual emissions will not significantly increase over it pre-change actual emissions. In fact, PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. Further, in projecting post-change emissions, Intermountain does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth, changes in fuel characteristics, variability in control technology performance (other than the one in the proposed change), etc.

Under the WEPCO rule, Intermountain must compute baseline actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change. Intermountain has provided these figures to verify its projection of no increase in actual emissions. Following the change, Intermountain must maintain and submit to the Executive Secretary on an annual basis for a period of at least 5 years from the date the units begin fully utilizing the modifications described herein as regular operation, information demonstrating that the renovation did not result in a significant emissions increase. If Intermountain fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the modifications at that time.

When using the WEPCO actuals to future actuals test, Intermountain must maintain and submit to the Executive Secretary, for a period of 5 years from the date the units full utilization of the Dense Pack project, information demonstrating that the project did not result in an emissions increase. To adequately track post-change emissions, this information must include records on annual fuel use and emissions. Intermountain may exclude emissions increases that are caused by other factors, such as variability in control technology performance or coal characteristics. In addition, when calculating emission increases, Intermountain may exclude that portion of its emissions attributable to increased use at the unit due to the growth in electrical demand for the utility system as a whole since the baseline period.

In this case, to avoid the onerous burden of reporting exhaustive information for 5 years, and then attempting to delineate between emissions applicable to these modifications and those operational attributes excluded from the actuals to future actual test to prove no significant net increase, Intermountain has elected to be bound by a federally enforceable permit limit to reduce the potential to emit of the facility.

For electric utility steam generating units, the post-change emission increase calculation is governed by regulations adopted in 1992 (57 Fed. Reg. 32314, July 21, 1992), commonly referred to as the "WEPCO rule," which the State of Utah has adopted. Although the WEPCO rule did not change the regulatory provision that establishes a unit's pre-change emissions, EPA announced that it would view any consecutive two-year period during the preceding five years as presumptively reflective of "normal source operations." In addition, EPA amended the regulations regarding a utility unit's post-change emissions in two ways. First, the rules allow utilities to project future emissions resulting from a particular change without committing to a permit restriction limiting the unit's potential to emit to a level below its maximum capacity to emit that pollutant, and second, provide that emissions increases independent of the physical or operational change may be discounted from the post-change emissions of the unit.

Therefore, a utility making a particular change, instead of accepting permit restrictions on the potential of the changed unit to emit a particular pollutant, may avoid PSD if its projection of "representative actual annual emissions" following the change is not significantly greater than its pre-change emissions. Conversely, if a utility accepts permit restrictions on the potential of the changed unit to emit a particular pollutant, it may avoid the tenuous task of maintaining and supplying to the DAQ substantial amounts of information that may be open to interpretation by both the facility and the agency. In determining whether an emissions increase is due to the modifications or to some excluded operational attribute, confusion and difficulty can arise in interpreting between the two. Intermountain does not have to count in any emissions increase those emissions that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the modifications, including any increased utilization. (Refer to EPA Region V letter of May 2000 to H. Nickel of Detroit Edison, "Dense Pack Project PSD Determination.")

Therefore, as a matter of clarity, Intermountain chooses to accept a federally enforceable permit limit to limit its PTE for NO_x, SO_2, and PM_{10} from the main boilers. It will use the "actuals to future actuals" test for those other pollutants for which a permit limit does not presently exist.

II. EMISSION SUMMARY

The emissions from the entire plant (including fugitives) will be as follows:

Pollutant	Current Actual Emissions (Last 2-year Average) tons/year	Emission Increases tons/year	Projected Future Actual Emissions tons/year
PM_{10}	820.32	9.75	830.07
SO_2	3586.31	0.00	3586.31
NO_x	25143.97	0.00	25143.97
CO	1317.06	77.56	1394.62
VOC	11.81	0.69	12.50
HAPs			
Lead	0.098	0.007	0.105
Beryllium	0.0012	0.00	0.0012
Mercury	0.081	0.024	0.105

Fluorides (HF)	9.70	0.42	10.12
Sulfuric Acid	4.06	0.00	4.06
Other HAPs (non-VOC)	59.38	0.40	59.78

Potential to Emit from the entire Plant (including fugitive emissions) will be as follows:

Pollutant	Current PTE tons/year	Emission Increases tons/year	Total PTE tons/year
PM_{10}	3,286.90	0.00	3,286.90
SO_2	11,332.30	0.00	11,332.30
NO_x	37,868.20	0.00	37,868.20
CO	1,891.10	98.50	1,989.60
VOC	62.57	1.41	63.91
HAPs			
Lead	0.386	0.00568	0.39
Beryllium	0.0089	0.0000	0.0089
Mercury	0.289	0.0245	0.31
Fluorides (HF)	15.500	1.30	16.80
Sulfuric Acid	8.10	0.70	8.80
Other HAPs (non-VOC)	86.20	7.00	93.20

*Denotes existing emissions from the existing cooling towers inadvertently omitted from the previous AOs

Plant Emission Summary (including fugitives)

Pollutant	Actual Annual Emissions (ton/yr)	Projected Future Emissions (ton/yr)	Emissions Increases Increase (ton/yr)
Boiler 1 &2 Stacks			
PM_{10}	281.53	291.25	9.72
SO_2	3,586.19	3,586.19	0.00
NO_X	25,143.82	25,143.82	0.00
CO	1,317.04	1,394.86	77.56
VOC	11.52	12.21	0.69
Other Sources			
PM_{10}	539.19	539.22	0.03
SO_2	0.12	0.12	0.00
NO_x	0.15	0.15	0.00
CO	0.02	0.02	0.00
VOC	0.29	0.29	0.00

III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

BACT applies to each emission point.
This review did not trigger PSD review.
There will a new emission point - helper cooling tower at this site as a result of this modification.

BACT for the helper cooling tower is the use of mist eliminators with 0.0015% drift per 1000 gallons of circulating water.

BACT analysis performed in previous engineering reviews apply to this modification.
Since the facility already has low-NOx burners, it is possible to stay below significant net increases in NO_x with minor adjustments in how coal is combusted, i.e., biased firing, such as burners-in-service arrangement, excess air, frequency of soot-blowing, etc. and adding of superheat tubes to eliminate transient temperature anomalies and provide stable and efficient operation at the new higher rating"

IV. APPLICABILITY OF FEDERAL REGULATIONS AND UTAH ADMINISTRATIVE CODES (UAC)

The Notice of Intent submitted is for an existing source. It is not a new major source or a major modification. At the time of this review the Utah Administrative Code Rules 307 (UAC R307) and federal regulations have been examined to determine their applicability to this Notice of Intent. The following rules have been specifically addressed.

1. R307-101-2, Modification
2. R307-107, UAC - Unavoidable breakdown reporting requirements.
3. R307-150 Series, UAC - Inventories, Testing and Monitoring.
4. R307-201-1(2), UAC - 20% minimum opacity limitation at all emission points.
5. R307-201-1(9), UAC - Opacity Observation.
6. R307-203. Emission Standards: Sulfur Content of the Fuel
7. R307-205 (UAC) - Emission Standards: Fugitive Emissions and Fugitive Dust.
8. R307-215. Emission Standards: Acid Rain
9. R307-401, Utah Administrative Code (UAC) UAC - Notice of Intent required for a modified source.
10. R307-405. Permits: Prevention of Significant Deterioration of Air Quality
11. R307-406, UAC - Visibility
12. R307-410, UAC - Permits: Emissions Impact Analysis (Air Quality Modeling)

V. RECOMMENDED APPROVAL ORDER CONDITIONS

General Conditions:

1. This Approval Order (AO) applies to the following company:

   Intermountain Power Service Corporation
   850 West Brush Wellman Road
   Delta, Utah 84624
   Phone Number: (435) 864-4414
   Fax Number: (435) 864-4970

   The equipment listed below in this AO shall be operated at the following location:

   PLANT LOCATION:

   850 West Brush Wellman Road, Delta, Millard County, Utah

   Universal Transverse Mercator (UTM) Coordinate System: datum NAD27
   4,374.4 kilometers Northing, 364.2 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307), and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. All records shall be kept for the following minimum periods:

   A. Emission inventories — Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.

   B. All other records — Five years

6. Intermountain Power Service Corporation (IPSC) shall conduct its operations of the *Intermountain Generating Station (IGS) coal fired electric steam plant in accordance with* the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on April 5, 2001, May 31, 2001, August 26, 2001, September 5, 2001, September 19, 2001, October 26, 2001.

7. This AO shall replace the AO (DAQE-749-01) dated September 11, 2001.

8. The approved installations shall consist of the following equipment or equivalent*:

A. Unit #1 Coal Fired Boiler (Subject to NSPS, Subpart Da)
   Rating - 9,225 x 10^6 Btu/hr (MMBtu/hr)
B. Unit #2 Coal Fired Boiler (Subject to NSPS, Subpart Da)
   Rating - 9,225 MMBtu/hr
C. Coal railcar unloading dust collector 1A
D. Coal railcar unloading dust collector 1B
E. Coal railcar unloading dust collector 1C
F. Coal railcar unloading dust collector 1D
G. Coal truck unloading dust collector 2
H. Coal reserve reclaim dust collector 3
I. Coal transfer building #1 dust collector 4
J. Coal transfer building #2 dust collector 5
K. Coal transfer building #4 dust collector 6
L. Coal crusher building dust collector 11
M. U1 Generation building coal dust collector 13A
N. U1 Generation building coal dust collector 13B I.
A. U2 Generation building coal dust collector 14A
B. U2 Generation building coal dust collector 14B
C. Coal pile active and reserve
D. Coal Stackout
E. Fuel oil tank 1A
   Capacity - 675,000 gallons
F. Fuel oil tank 1B
   Capacity - 675,000 gallons
G. Limestone unloading dust collector 1A
H. Limestone unloading dust collector 1B
I. Limestone transfer dust collector 1
J. Limestone reclaim dust collector 2
K. Limestone silo bin vent filter
L. Limestone crusher dust collector 3
M. Limestone preparation dust collector 4
N. Limestone storage pile
O. Lime silo dust collector 1
P. Lime hopper dust collector 2
Q. Soda ash silo dust collector 3
R. Soda ash hopper dust collector 4
S. Fly ash silo bin vent filter 1A
T. Fly ash silo bin vent filter 1B
U. Combustion byproducts stackout & stockpile
V. Combustion byproducts landfill
W. Unit 1 cooling tower 1A
X. Unit 1 cooling tower 1B
Y. Unit 2 cooling tower 1A
Z. Unit 2 cooling tower 1B

AA. Coal sample preparation building dust collector
BB. Sandblast facility dust collector
CC. U1 Generation building vacuum cleaning dust collector
DD. U2 Generation building vacuum cleaning dust collector
EE. U1 Fabric filter vacuum cleaning dust collector
FF. U2 Fabric filter vacuum cleaning dust collector
GG. GSB vacuum cleaning dust collector
HH. Guzzler truck dust collector
II. Emergency diesel generators

1A, rated at -	4,000 Hp
1B, rated at -	4,000 Hp
1C, rated at -	4,000 Hp

JJ. Solvent washers
KK. Diesel driven fire pump rated at 290 Hp 1B
LL. Diesel driven fire pump rated at 290 Hp 1C
MM. Auxiliary boiler 1A (not subject to NSPS)
Rating - 166 MMBtu/hr
NN. Auxiliary boiler 1B (not subject to NSPS)
Rating - 166 MMBtu/hr
OO. Coal Conveyors
PP. Paint booth/shops
QQ. Engine driven equipment including compressors, generators, hydraulic pumps and diesel fire pumps
RR. Bulb recycling crusher
SS. Laboratory fume hoods
TT. Gasoline tank
Capacity - 500 gallons
UU. Diesel tank
Capacity - 10,000 gallons
VV. Diesel day tanks
Capacity - not exceeding 560 gallons per tank
WW. Mobile oil storage tanks
Capacity - not exceeding 12,000 gallons per tank
XX. Turbine lube oil units
Capacity - not exceeding 40,000 gallons per unit
YY. Underground storage diesel tank
Capacity - 20,000 gallons
ZZ. Underground storage gasoline tank
Capacity - 6,000 gallons
AAA. Used oil tank
Capacity - 10,000 gallons
BBB. Class III Industrial Waste Landfill
CCC. Paved haul road
DDD. Haul road and access road
EEE. Coal truck unloading grating
TTT. Helper cooling tower

* Equivalency shall be determined by the Executive Secretary.

Limitations and Tests Procedures

1. Emissions to the atmosphere at all times from the indicated emission points shall not exceed the following rates and concentrations:

A. **Each Main Boiler Stack**

Before the Modification (While Rated at 8,500 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	
PM_{10}	0.020*	lb/ 10^6 Btu heat input
SO_2	0.15**	lb/ 10^6 Btu heat input based on 30-day rolling-average 10.0 % of the potential combustion concentration
NO_x	0.50**	lb/ 10^6 Btu heat input based on 30-day rolling-average

After the Modification (While Rated at 9,225 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	
PM_{10}	0.0184 *	lb/ 10^6 Btu heat input
SO_2	0.138 **	lb/ 10^6 Btu heat input based on 30-day rolling-average 10.0 % of the potential combustion concentration
NO_x	0.461**	lb/ 10^6 Btu heat input based on 30-day rolling-average

B. Testing Status (To be applied above)

* Test once a year. The Executive Secretary may require testing at any time.

**Compliance for NO_x and SO_2 emissions shall be demonstrated through use of a continuous emissions monitoring system as outlined in Condition 24.

Dust Collectors

Pollutant/Source	differential pressure across the dust collector (inches of water gage)
PM_{10}	
Rail car unloading (4 units)	0.5 and 12*
Transfer building one	0.5 and 12*
Unit one 13A	0.5 and 12*
Transfer building two	0.5 and 12*

Transfer building four	0.5 and 12*
Crusher building one	0.5 and 12*
Unit one 13B	0.5 and 12*
Unit two 14A	0.5 and 12*
Unit two 14B	0.5 and 12*
Limestone preparation building	0.5 and 12*

* If differential pressure is less than 2 inches or greater than 10 inches, work orders will be written to investigate. Dust collector may run in the 0.5 to 2 or 10 to 12 range if reason is known. Intermittent recording of the reading is required on a monthly basis. The instrument shall be calibrated against a primary standard annually. The primary standard shall be established by the company and shall be submitted to the Executive Secretary for approval. Preventive maintenance shall be done quarterly on each baghouse.

Each Auxiliary Boiler (Rated at 166 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	lbs/hr
PM_{10}	0.10	20
SO_2	0.69	100
NO_x	0.35	58

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required .... emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, and stack to be tested. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. Access that meets the standards of the Occupational Safety and Health Administration (OSHA) or the Mine Safety and Health Administration (MSHA) shall be provided.

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2

F. PM_{10}

For stacks in which no liquid drops are present, the following methods for informational purposes shall be used: 40 CFR 51, Appendix M, Methods 201 or 201a. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5b, 5d, or 5e as appropriate. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth addition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

G. Calculations

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

H. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

2. Visible emissions from the following emission points shall not exceed the following values:

A. All abrasive blasting - 40% opacity
B. All other points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9.

For sources that are subject to NSPS opacity standards shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9.

3. The following consumption limit shall not be exceeded:

50,000 barrels of fuel oil consumed per calendar year in the auxiliary boilers.

To determine compliance with this annual limit, the owner/operator shall calculate a total by the January 20th of each year using data from the previous 12 months (ending with December 31). Records of consumption shall be kept for all periods when the auxiliary boiler is in operation. Consumption shall be determined by fuel oil totalizer records. The records of consumption shall be kept on a monthly basis.

4. Annual emissions from the entire plant shall not exceed the following amounts:

CO .... 1989.60* tons per rolling12-month period

* Emission factors for CO shall be derived from the most recent EPA's Compilation of Air Pollutant Emission Factors (AP-42), industry specific published emission factors (such as Electric Power Research Institute, Edison Electric Institute), fuel analysis, IPSC own testing, and acceptable engineering judgment as appropriate.

5. Emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, except for routine engine maintenance and testing. Records documenting generator usage shall be kept in a log and shall show the date the generator was used, the duration in hours of generator usage, and the reason for each usage.

6. The diesel driven fire pumps shall be operated on an emergency basis only, except for routine engine and fire system maintenance and testing. Records documenting diesel driven fire pump usage shall be kept in a log and shall show the date the diesel driven fire pump was used, the duration in hours of use, and the reason for each usage.

Roads and Fugitive Dust

7. IPSC shall abide by the latest fugitive dust control plan submitted to the Executive Secretary for control of all dust sources associated with the Intermountain Power Generation site.

   The haul road length, speed or any other parameter used to calculate emissions shall not be increased above the limits established in the fugitive dust control plan. Any haul road speeds established in the plan shall be posted.

8. The facility shall abide by all applicable requirements of R307-205 for Fugitive Emission and Fugitive Dust sources.

Fuels

9. The owner/operator shall combust only bituminous and subbituminous coals as primary fuels and shall only use diesel oil or natural gas during the startup, shutdown, maintenance, performance, upsets and flame stabilization in the 9,225 x 10^6 Btu/hr boilers. Only No. 2 oil shall be used in 166 x 10^6 Btu/hr boilers. The owner/operator may fuel-blend self-generated used oil with coal at the active coal pile reclaim structure providing that self-generated used oil has not been mixed with hazardous waste.

10. The sulfur content of any fuel oil combusted shall not exceed:

    A. 0.85 lb per x 10^6 Btu heat input for fuel oil used in the main boilers.
    B. 0.58 percent by weight for fuel oil combusted in the auxiliary boilers.

    The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall be either by IPSC's own testing or test reports from the fuel oil marketer.

Federal Limitations and Requirements

11. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18 and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) and Subpart Y, 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants) apply to this installation.

12. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 - Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Records & Miscellaneous

13. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded, and the records shall be maintained for a period of two years.

14. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

15. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

Monitoring - Continuous Emissions Monitoring

16. The owner/operator shall install, calibrate, maintain, and continuously operate a continuous emissions monitoring system (CEMs) on the main boilers stacks and SO_2 removal scrubbers outlets. The owner/operator shall record the output of the system, for measuring the opacity, SO_2, NO_x, CO_2 emissions. The monitoring system shall comply with all applicable sections of R307-170, UAC; and 40 CFR 60, Appendix B.

    All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

    Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring devices and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section UAC R307-170.

17. In order to demonstrate that modification did not result in significant emissions increases, the rolling 12-month period (compiled quarterly) main boilers 1&2 fuel consumption data (MMBtu/hr) and emissions from their stacks shall be monitored for at least 5 years from the

date the units begin fully using the modifications described herein as regular operation. If IPSC fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for these modifications at that time. Records of NO_x and SO_2 shall be obtained through the use of a CEM. Records of PM_{10} shall be based on annual stack tests outlined in the Condition 9. Records for the rest of pollutants shall be based on the EPA's Compilation of Air Pollutant Emission Factors (AP-42), industry specific published emission factors (such as Electric Power Research Institute, Edison Electric Institute or IPSC own testing).

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.eq.state.ut.us/eqair/aq_home.htm

The annual emission estimations below include point source, fugitive emissions, fugitive dust and do not include road dust, tail pipe emissions, grandfathered emissions etc.. These emissions are for the purpose of determining the applicability of Prevention of Significant Deterioration, nonattainment area, maintenance area, and Title V source requirements of the R307. <u>They are not to be used for determining compliance</u>.

The Potential To Emit (PTE) emissions for the IPSC power generation plant are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10}	3,286.90
B.	SO_2	11,332.30
C.	NO_x	37,868.20
D.	CO	1,989.60
E.	VOC	63.91
F.	HAPs	82.67
	Lead	0.39
	Beryllium	0.0089
	Mercury	0.31
	Fluorides (HF)	16.80
	Sulfuric Acid	8.80
	Other non-VOC HAPs	93.20

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